PUBLIC VERSION
DIRECT TESTIMONY OF DEREK P. STENCLIK ON BEHALF OF SIERRA CLUB DOCKET NO. 2019-226-E

INTRODUCTION AND QUALIFICATIONS

Q: Please state your name, position, and business address for the record.

A: My name is Derek Stenclik and I am the President of Telos Energy, Inc. My business address is 475 Broadway, Unit 6, Saratoga Springs, NY 12866.

Q: Please summarize your professional and educational qualifications.

A: I am the founding partner of Telos Energy, Inc., an analytics and technology company specializing in grid planning and technologies that enable renewable integration. I have a decade of experience helping clients across the electric power industry navigate evolving markets, adapt to rapidly changing technologies, and accelerate clean energy integration. I specialize in production cost modeling for grid planning, asset development, wind and solar integration, and battery energy storage.

I also perform modeling analyses of electric power systems. I am proficient in the use of spreadsheet analysis tools, as well as optimization and electricity dispatch models and resource adequacy models to conduct analyses of utility service territories and regional energy markets. I have direct experience running the PLEXOS, GE MAPS, and SERVM models, and have reviewed input and output data for several other industry models.

From 2011 to 2018, I was employed by GE Energy Consulting, most recently as the Senior Manager of Power Systems Strategy. In that role I was responsible for a team of engineers and economists that conducted economic and transmission planning studies for utilities, grid operators, and developers across North America.

I hold a master's degree in Applied Economics and Management from Cornell University and graduated with Summa Cum Laude and Phi Beta Kappa honors from State University of New York, College at Geneseo. Additional qualifications are included in my current resume, attached as Exhibit DS-1.

Q: Have you previously testified as an expert witness before the Public Service Commission of South Carolina (The "Commission")?

A: Yes, I filed expert testimony and appeared before the Public Service Commission of South Carolina in Dominion Energy South Carolina's 2019 Avoided Cost Proceeding, Docket 2019-184-E, on behalf of The South Carolina Coastal Conservation League and the Southern Alliance for Clean Energy.

Q: On whose behalf are you testifying in this proceeding?

A: I am submitting this testimony on behalf of the Sierra Club.

Q: Are you sponsoring any exhibits?

A: Yes, I am sponsoring the following exhibits:

Exhibit Number	Description of Exhibit	Confidential or Non-Confidential
Exhibit DS-1	Resume of Derek Stenclik	Non-Confidential
Exhibit DS-2	DESC Response to ORS 1-17	Non-Confidential
Exhibit DS-3	DESC Response to ORS 2-18	Confidential
Exhibit DS-4	DESC Response to ORS 2-26	Non-Confidential
Exhibit DS-5	DESC Response to ORS 5-13	Non-Confidential
Exhibit DS-6	DESC Response to ORS 6-4	Non-Confidential
Exhibit DS-7	DESC Response to ORS 6-9	Confidential

Q: What is the purpose of your direct testimony in this proceeding?

A: The purpose of my direct testimony is to review and evaluate various components of Dominion Energy South Carolina's ("DESC" or "the Company") 2020 Integrated Resource Plan ("IRP"). I discuss alternative assumptions that should be used in DESC's long-term planning, identify risks of continued coal operation, provide alternative resource plans to the ones proposed by DESC, and recommend that the Commission take actionable steps to retire coal generation and replace it with modern, clean, and flexible technologies.

Q: Please identify the documents and filings on which you base your opinions regarding DESC's 2020 IRP.

A: In addition to the Company's IRP and related appendices and supporting documents, I reviewed DESC's responses to discovery filed by Office of Regulatory Staff and other intervening parties. I also reviewed DESC's (and formerly South Carolina Electric and Gas's ("SCE&G")) annual FERC Form 714 filings, and a number of industry publications, news articles and press releases.

Q: Do you have recent experience evaluating coal retirements in other jurisdictions?

A: Yes. In the past year I provided technical analysis and modeling related to two coal retirement decisions, both of which were presented to state regulators. One analysis evaluated the reliability implications of retiring a coal plant in Hawaii and replacing it with hybrid solar+storage plants.[1] The second analysis evaluated alternative replacement portfolios to the San Juan coal retirement in New Mexico.[2]

OVERVIEW OF TESTIMONY AND CONCLUSIONS

Q: How is your testimony organized?

A: My testimony is organized into four sections, outlined below:

1. Review of IRP Assumptions
   a. Improved Capital Cost Assumptions
   b. Improved Load Forecast Assumptions
2. Risks of Continued Coal Operations
3. Independent Modeling of Alternative Portfolios
4. Recommendations for the Commission

Q: In your opinion, does the modeling performed by DESC in its 2020 IRP result in reasonable future resource plans?

A: No, it does not. DESC's least cost resource plan (Resource Portfolio 2, "RP2") is based on inappropriate assumptions, including load forecasts that are too high, combustion turbine capital cost that are too low, and battery storage cost that are too high. This resulted in portfolios that continue to operate coal indefinitely, do not include additions of renewable generation, and do not integrate battery energy storage technology.

My independent modeling indicates that when assumptions are revised to more appropriate values, DESC's least cost and lowest CO_2 plan would change significantly.

[1] Work conducted for ongoing engagement with the Hawaii Natural Energy Institute, in collaboration with the Hawaii Public Utilities Commission and Hawaiian Electric Company. https://www.hnei hawaii.edu/projects#GI.

[2] Direct Testimony of Michael Milligan, "Public Service Company of New Replacement for San Juan Generating Station," Case No. 19-00195, December 13, 2019.

Based on this analysis, DESC should retire Wateree and Williams before 2028 and avoid unnecessary capital expenditures and operations and maintenance costs, and plan for additional solar and storage resources. This would save DESC ratepayers $14.4M, compared to DESC's proposed least cost portfolio.

REVIEW OF IRP ASSUMPTIONS

Improved Capital Cost Assumptions

Q: Did you review DESC's IRP assumptions and if so, which ones did you focus on?

A: Yes, I reviewed DESC's IRP assumptions in detail. While there are many that could be changed, I focused my testimony on two key assumptions that have the largest impact on the IRP results and therefore, pose the largest risk to DESC ratepayers: DESC's capital cost assumptions for new battery storage and combustion turbine technologies, and the underlying load forecast assumptions. The lack of attention towards other assumptions does not imply acceptance of or support for DESC's assumptions.

My testimony focuses on these two key assumptions in particular and my analysis made limited additional changes to the IRP assumptions. This was done to simplify the comparison to DESC's own analysis. The other changes included the following:

- The assumed battery storage project life from 10 years to 15 years to be consistent with the NREL Annual Technology Baseline (ATB) forecast[3] and industry trends.

[3] NREL (National Renewable Energy Laboratory). "2019 Annual Technology Baseline." Golden, CO: National Renewable Energy Laboratory. https://atb nrel.gov/electricity/2019.

- The transmission interconnection cost assumed for the solar and storage technologies to be the same as the thermal generators as there was no clear explanation by DESC for the difference.
- The chronological, hourly load profile and solar profiles were adjusted to use publicly available data and the same 2017 weather year. The load profile used the Federal Energy Regulatory Commission (FERC) Form No. 714 - Annual Electric Balancing Authority Area and Planning Area Report[4] hourly load filings and the solar data utilized NREL's National Solar Radiation Database (NSRDB) and System Advisor Model.[5]

Q: Did you review DESC's IRP assumptions regarding potential resource additions?

A: Yes, I reviewed DESC's IRP for assumptions related to capital costs of potential resource additions, provided on Page 39 of the IRP. The table "Description of Potential Resources" includes assumptions for the capital cost and escalation rate of potential technologies available to meet DESC's future resource needs. I also reviewed the "Independent Review of the 2020 DESC IRP" performed by Charles River Associates ("CRA" or "Charles River"),[6] which provided an independent review of DESC's capital cost assumptions.

Q: What is your reaction to the capital cost assumptions provided by DESC?

A: In my opinion, the capital cost assumptions used by DESC, specifically related to internal combustion turbine (ICT) and battery storage, are drastically inaccurate and are not

[4] Federal Energy Regulatory Commission, "Form No. 714 - Annual Electric Balancing Authority Area and Planning Area Report," https://www.ferc.gov/industries-data/electric/general-information/electric-industry-forms/form-no-714-annual-electric/data.
[5] National Renewable Energy Laboratory, "National Solar Radiation Database," https://nsrdb.nrel.gov/.
[6] Direct Testimony of Eric H. Bell, Exhibit 2, "Independent Review of the 2020 DESC IRP," Page 159-160.

reflective of other assumptions used throughout the industry for long-term planning. The ICT assumption is significantly lower than industry cost estimates by up to 58%[7] and the battery storage assumption is significantly higher than industry cost estimates by 54%.[8]

Q: Why is the accuracy of these capital cost assumptions important?

A: The capital cost assumptions for potential resource additions is one of the most critical assumptions since it determines which technologies are selected in long term planning and the cost efficacy of coal retirements. While the modeling also incorporates operational costs, such as fuel and maintenance costs, the capital costs are over 70% of the total levelized cost of electricity for some technologies. The capital cost assumption is extremely important for resources such as combustion turbines, which are used infrequently as a peaking resource, and solar and battery storage, which do not have variable costs associated with their generation. For example, 70% of the total levelized cost of energy (LCOE) of combustion turbines, and over 90% for solar photovoltaic (PV) and batteries, is based on the upfront capital cost.[9] As a result, small adjustments to capital costs of CT, PV, or battery storage can drastically alter the competitiveness of those resources.

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[7] PJM, "Preliminary Default MOPR Floor Offer Prices for New Generation Capacity Resources," Page 4 (February 28, 2020), available at https://www.pjm.com/-/media/committees-groups/committees/mic/2020/20200228-mopr/20200228-item-03a-pjm-preliminary-cone-values.ashx.

[8] Based on an average of IHS Markit, Wood Mackenzie, and Bloomberg New Energy Finance. Available from Indianapolis Power & Light Company, "IPL 2019 IRP: Public Advisory Meeting #2," March 26, 2019, Page 87.

[9] Lazard, "Levelized Cost of Energy Analysis, Version 13," November 2019, available at https://www.lazard.com/media/451086/lazards-levelized-cost-of-energy-version-130-vf.pdf

Q: Can you elaborate on your observations related to the assumed combustion turbine capital costs?

A: Yes. DESC assumed a capital cost for an ICT Frame J of $469/kW, citing their own internal "Dominion Energy Services – Generation Construction Financial Management & Controls" as the original source of the assumption.[10] Based on my experience, this is almost 50% lower than other industry sources. For comparison purposes, the 2019 NREL Annual Technology Baseline (ATB) assumes an overnight capital cost of $899/kW[11] for combustion turbine technology. PJM, which annually estimates capital costs of new generation for its capacity market review, assumes a capital cost of $875/kW for combustion turbine technology.[12]

In addition, prior to forming Telos Energy, I was employed with GE Energy Consulting, a division of GE Power. GE Power is one of the largest and most established manufacturers of gas combustion turbines globally. In that role, I regularly interfaced with the frame gas turbine and aeroderivative gas turbine commercial teams. Based on that experience, I believe the capital costs of new combustion turbine technology is more in line with NREL and PJM assumptions than DESCs.

Q: Do you have any observations related to DESC's assumptions for aeroderivative combustion turbine technology?

A: Yes. DESC identified two types of gas turbine technology in their IRP as potential resources: a conventional ICT Frame J technology and an ICT Aero (aeroderivative)

[10] Direct Testimony of Eric H. Bell, Exhibit 1, "2020 Integrated Resource Plan," Page 42.
[11] NREL (National Renewable Energy Laboratory). "2019 Annual Technology Baseline." Golden, CO: National Renewable Energy Laboratory. https://atb nrel.gov/electricity/2019.
[12] *See* n7, *Preliminary Default MOPR Floor Offer Prices for New Generation Capacity Resources.*

technology.[13] An aeroderivative gas turbine ("Aero") is typically smaller and more flexible than conventional frame gas turbines. For the Aero technology, DESC assumed a more reasonable price of $918/kW. Because of this higher price compared to the flawed $469/kW ICT Frame J assumption, DESC did not select the Aero units as expansion resources in any scenario *except* RP8, which evaluated the coal retirements. DESC provided no justification for its selection of the Aero unit for RP8 and it does not appear to be based on an economic criterion or otherwise. This addition is twice as expensive as the ICT Frame technology and makes RP8 unnecessarily less economic. This resource should be replaced with an ICT frame technology.

Q: Did Charles River Associates provide an independent review of the combustion turbine capital cost?

A: Yes, Charles River Associates provided an independent, but misleading, review of the assumed combustion turbine capital costs.[14] In its review, Charles River Associates included a chart showing the DESC capital cost assumptions versus various public sources and Utility IRPs.[15] In that chart, provided in the figure below, the DESC assumptions for ICT frame and Aero capital costs were combined on the same plot and compared against other sources. This makes it appear that the DESC assumptions are within the range of industry assumptions, but in reality, the Aero is in the range of industry assumptions, but the ICT frame is the lowest price included in that analysis and falls far outside of the industry standard. The scale of the axis also makes it seem as if the DESC assumption is closer to its peers than it is.

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[13] Direct Testimony of Eric H. Bell, Exhibit 1, "2020 Integrated Resource Plan," Page 42.
[14] Direct Testimony of Eric H. Bell, Exhibit 2, "Independent Review of the 2020 DESC IRP," Page 61-62.
[15] Direct Testimony of Eric H. Bell, Exhibit 2, "Independent Review of the 2020 DESC IRP," page 160, Figure 22.

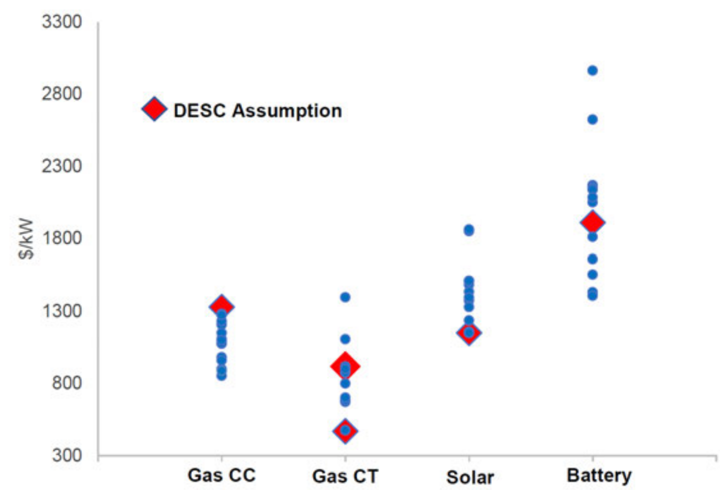

Figure 1: Capital Costs – DESC vs. Public Sources and Utility IRPs, from CRA Report

Q: What is your recommended capital cost assumption for combustion turbine technology?

A: I recommend that the Commission require DESC to use the NREL ATB assumption of $899/kW for new combustion turbine and Aero technologies in the current 2020 IRP as well as in future IRPs. The NREL ATB is a regularly updated, independent source of capital cost assumptions used by grid planners throughout the country.[16] In addition, the Commission should require that DESC utilize actual project bid data for resource planning. This is a best practice being adopted throughout the industry. Examples of this include PNM's San Juan Replacement[17] and HECO's Integrated Grid Planning[18] efforts. This ensures that new candidate resources are evaluated based on current pricing trends

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[16] NREL (National Renewable Energy Laboratory). "2019 Annual Technology Baseline." Golden, CO: National Renewable Energy Laboratory, available at: https://atb nrel.gov/electricity/2019.
[17] Public Service of New Mexico, *Powering the Future - Exit from Coal*, available at: https://www.pnmforwardtogether.com/poweringthefuture.
[18] Hawaiian Electric Company, *Integrated Grid Planning,* available at: https://www.hawaiianelectric.com/clean-energy-hawaii/integrated-grid-planning.

rather than aging industry reports. This is especially important for near-term retirement and replacement decisions.

Q: Can you elaborate on your observation related to the assumed battery storage capital costs?

A: Yes. DESC, based on its own internal documents, assumed a capital cost for battery storage of $1911/kW, or $477.75/kWh, where kWh refers to the energy rating of the storage device assumed from a 4-hour duration resource.[19]

Telos Energy regularly supports clients that develop battery storage projects around the country with services related to project economics and forecasting.[20] This affords me with up-to-date pricing information, which is based on actual supplier quotes, rather than industry reports. This is important because battery prices are rapidly falling.[21,22] By the time an industry report is analyzed, written, and published, battery prices have already changed significantly. Based on my expert opinion and experience, DESC's battery storage cost assumptions are as much as 60% higher than current battery storage prices. For comparison purposes, other capital cost assumptions are provided in Table 1 below.

[19] Direct Testimony of Eric H. Bell, Exhibit 1, "2020 Integrated Resource Plan," Page 42.
[20] Telos Energy's clients include some of North America's largest renewable energy and battery storage developers. For a list of current and recent projects please see https://www.google.com/maps/d/edit?mid=1nZD-1gHYTKLo_E7gsvT7w3dEPSMfSvXD&usp=sharing
[21] St. John, Jeff, "Levelized Cost of Energy for Lithium-Ion Batteries Is Plummeting," Greentech Media, March 26, 2019, available at https://www.greentechmedia.com/articles/read/report-levelized-cost-of-energy-for-lithium-ion-batteries-bnef?utm_medium=email&utm_source=Daily&utm_campaign=GTMDaily#gs.37hoqj
[22] Colthorpe, Andy, "Behind the Numbers: The Rapidly Falling LCOE of Battery Storage," May 6, 2020, available at https://www.energy-storage.news/blogs/behind-the-numbers-the-rapidly-falling-lcoe-of-battery-storage

Table 1: Alternative Battery Capital Cost Assumptions by Source

Source	4-hour Battery Cost ($/kWh)
NREL 2019 ATB (Mid)	321
California PUC IRP (Mid)	313
Industry Consultant Average[23]	302
DESC 2020 IRP	478

The NREL ATB assumed a mid-price of $321/kWh for battery storage, declining to $203/kWh in 2030. In the California statewide 2019/2020 IRP and Long Term Procurement Plan, the California Public Utilities Commission utilized a mid-capital cost assumption of $313/kWh.[24] This is notable because California utilities have deployed a significant amount of utility-scale storage systems, and IRP intervenors in that case, submitted numerous comments that the assumed capital cost assumptions for battery storage, at $313/kWh, was too high based on recent market activity. According to the CPUC, even after using the a relatively low capital cost assumption, "there were particular complaints about solar and battery cost assumptions not aligning with market prices, and therefore representing higher costs than parties would have preferred."[25]

The economics of battery energy storage as a fossil plant replacement is now favorable. Florida Power & Light (FPL) recently announced that it plans to build a 409 MW/900 MWh battery storage project, the Manatee Energy Storage Center, powered by an

[23] Industry Consultant average included an average of IHS Markit, Wood Mackenzie, and Bloomberg New Energy Finance. Indianapolis Power & Light Company, *IPL 2019 IRP: Public Advisory Meeting #2,* March 26, 2019. Page 87.
[24] California Public Utilities Commission, "Administrative Law Judge's Ruling Seeking Comment on Proposed Reference System Portfolio and Related Policy Actions, Attachment C: Inputs and Assumptions," 2019-2020 Integrated Resource Plan. Rulemaking 16-02-007. November 6, 2019.
[25] California Public Utilities Commission, "Proposed Decision of ALJ Fitch," 2019-2020 Integrated Resource Plan. Page 10, available at https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M327/K750/327750339.PDF.

existing solar plant in order to help phase out two units at its gas-fired Manatee Clean Energy Center.[26] In addition, Hawaiian Electric Company recently selected a 185 MW, 565 MWh Kapolei Energy Storage project to replace the retirement of the state's largest 180 MW coal-fired AES power plant.[27]

In addition, Indianapolis Power & Light Company, as part of its 2019 IRP Stakeholder Process, surveyed three market vendors of price forecasts, including IHS Markit, Wood Mackenzie, and Bloomberg New Energy Finance.[28] The average of this "industry consultant forecast" is $302/kWh. A chart combining the forecasts of these sources is provided in Figure 2, below.

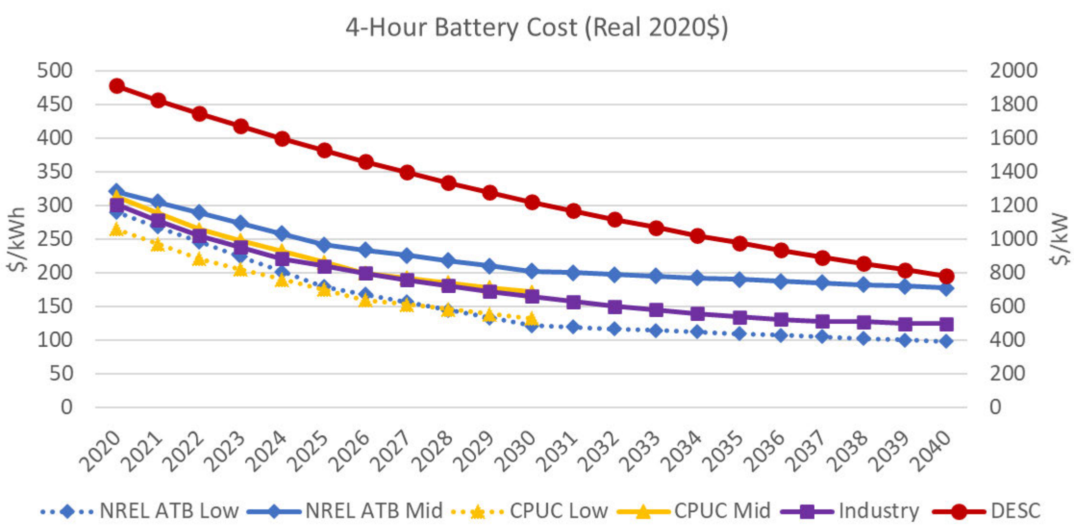

Figure 2: Comparison of Industry Forecasts for Battery Storage Capital Costs

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[26] Florida Power and Light, "FPL announces plan to build the world's largest solar-powered battery and drive accelerated retirement of fossil fuel generation," available at http://newsroom fpl.com/2019-03-28-FPL-announces-plan-to-build-the-worlds-largest-solar-powered-battery-and-drive-accelerated-retirement-of-fossil-fuel-generation.
[27] Hawaiian Electric Company, "Hawaiian Electric selects 16 projects in largest quest for renewable energy, energy storage for 3 islands," May 11, 2020, available at https://www hawaiianelectric.com/hawaiian-electric-selects-16-projects-in-largest-quest-for-renewable-energy-energy-storage-for-3-islands.
[28] Indianapolis Power & Light Company, *IPL 2019 IRP: Public Advisory Meeting #2,* March 26, 2019. Page 87.

Q: In your opinion, does the industry have a successful track record in forecasting new technology costs?

A: No. The industry has a poor track record of forecasting costs of new technology. When comparing the cost projections of the NREL ATB, US Energy Information Administration (EIA) Annual Energy Outlook, and other industry sources over many years, actual cost reductions have outpaced industry forecasts significantly for wind, solar, and battery storage technology. An example of this trend is presented below, from a recent study performed by UC Berkeley's Center for Environmental Public Policy.[29] The rapidly falling costs of wind and solar technology outpaced even low-end industry forecasts. As a result, the NREL ATB can be considered potentially conservative for future technology costs, and actual battery costs will likely be closer to the ATB low case or fall somewhere in between the ATB low and ATB mid case.

[29] UC Berkeley's Center for Environmental Public Policy, GridLab, and Energy Innovation. *2035 Report*, available at https://www.2035report.com/.

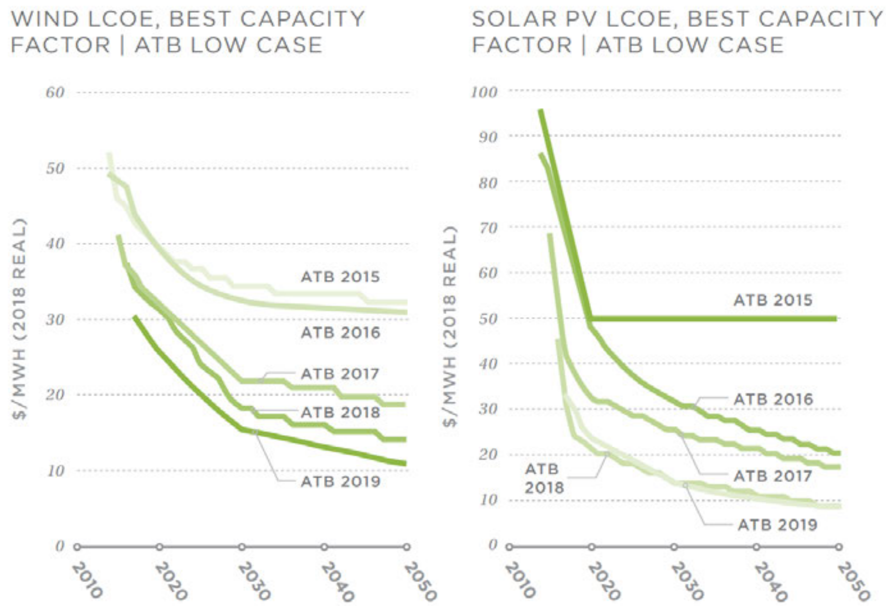

Figure 3: National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB) Low Case Cost Projections Made 2015–2019 for Years Through 2050

Q: What is your recommended assumption for battery technology costs?

A: I recommend that the Commission require DESC to use the NREL ATB mid-case assumption of $321/kWh ($1,284/kW) for the capital cost of battery storage, and the associated projected cost declines over time, also used by DESC, in the current 2020 IRP and in future IRPs. This assumption should be made recognizing that it is rather conservative and starts the forecast above current industry pricing.

Q: If the combustion turbine and battery storage costs are updated to more realistic numbers, does it change the results of DESC's IRP results?

A: Yes. Making these changes, and no others, causes the DESC RP8 Portfolio to be the lowest cost plan, and 1.3% lower than DESC's RP2. In the CO_2 case, RP8 remains the lowest cost option. The results of this analysis are provided in Table 2 below for the Base Gas, Medium DSM scenario. This clearly illustrates the importance of the underlying capital cost assumptions, foregone benefits for DESC ratepayers who would not benefit from cost declines of new technology, and illustrates why DESC should be required to re-run their model using more accurate capital cost assumptions.

Table 2: Resource Plan Levelized NPV Calculations for with Updated Capital Cost Assumptions

	NPV		Rank		Delta to RP2	
	DESC	Updated CapEx	DESC	Updated CapEx	DESC	Updated CapEx
RP1	1,249,160	1,276,285	5	4	1.4%	0.2%
RP2	1,231,667	1,273,187	1	3	0.0%	0.0%
RP3	1,251,077	1,287,797	6	7	1.6%	1.1%
RP4	1,239,802	1,291,651	3	8	0.7%	1.5%
RP5	1,266,727	1,283,473	7	5	2.8%	0.8%
RP6	1,246,165	1,286,625	4	6	1.2%	1.1%
RP7	1,236,518	1,266,520	2	2	0.4%	-0.5%
RP8	1,267,624	1,256,292	8	1	2.9%	-1.3%

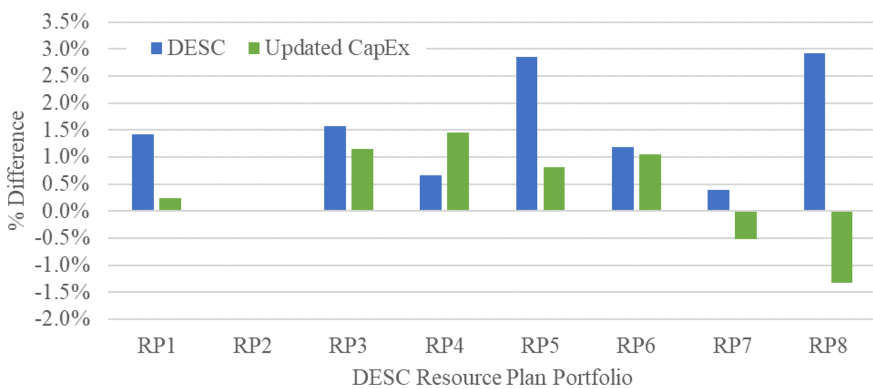

Figure 4: Difference of Portfolio NPV to DESC RP2

Improved Load Forecast Assumptions

Q: Why is the load forecast an important assumption for the IRP analysis?

A: The load forecast is one of the other most important assumptions in the IRP analysis, specifically the summer and winter peak loads. This is because the peak load values fundamentally determine the reserve margin calculation and the need for new capacity.

Based on DESC's planning criteria, there needs to be enough firm capacity to meet 112% of summer peak demand, and 114% of winter peak demand. As a result, every 100 MW of peak demand growth directly corresponds to 14 MW of additional new capacity that is required in the latter years of the forecast. Overestimating peak demand, could therefore lead directly to an over-procurement of capacity for DESC ratepayers.

Q: Have you reviewed the load forecast assumptions in the IRP?

A: Yes.

Q: What are your concerns with DESC's load forecast?

A: DESC's load forecast is too high. I reviewed the load forecast used in the IRP and compared it against recent historical loads and previous forecasts. To complete this, I downloaded DESC's (and formerly SCE&G) historical load forecasts from 2006 to 2018 available from FERC Form 714.[30] Each year, balancing authorities and planning areas across the United States are required to provide file "Form No. 714 - Annual Electric Balancing Authority Area and Planning Area Report." Included in this filing is the balancing authority's previous years hourly demand and a forecast of the following 10 years of annual energy and peak demand. This data is made available for each year back to 2006.

Based on a review of this data I do not have confidence that the DESC load forecast, specifically related to peak demand, is accurate. While DESC's load growth rates are

[30] Federal Energy Regulatory Commission, *Form No. 714 - Annual Electric Balancing Authority Area and Planning Area Report*, available at https://www.ferc.gov/industries-data/electric/electric-industry-forms/form-no-714-annual-electric-balancing-authority-area-and-planning-area-report-overview

relatively modest, they are still overly optimistic, and the starting point of the forecast appears arbitrarily high. This is based on several observations.

The first reason to believe DESC's long-term load forecast is likely overstating long-term load growth is based on observations from recent load forecasting activities. Based on FERC 714 filings, Figure 5 shows the 10-year winter peak load forecast provided by DESC for every year going back to 2006, as well as actual values and the IRP forecast. This chart clearly shows a regular bias in overstating the expected load growth by DESC. While recent forecasts have better adjusted for this trend, there is no reason to think that this forecast will be more accurate a few years from now.

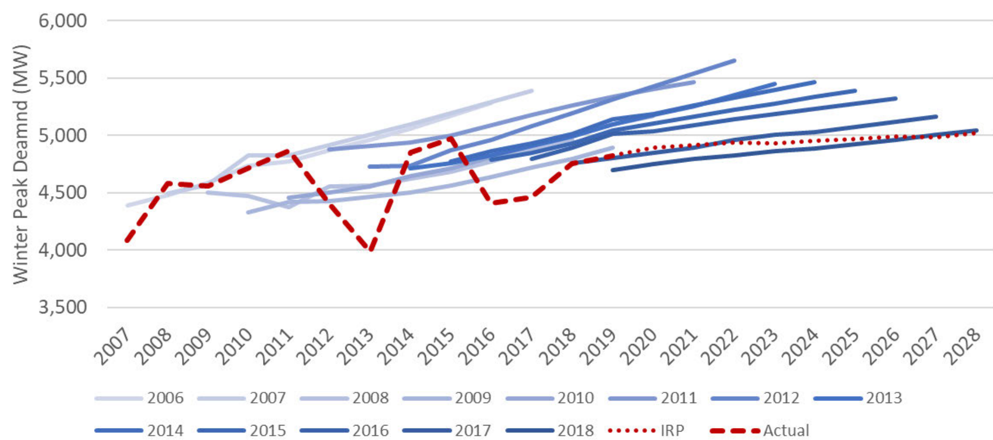

Figure 5: 13-years of DESC Load Forecasting, 2006 – 2018

It should also be noted that this bias is not unique to DESC, but rather quite common across the industry. Since the 2008 recession, load growth has not materialized in many regions and has fallen short of expectations. DESC's use of regression analysis for forecasting load is common practice for the industry, but it does have limitations. Regression analysis for load forecasting assumes that future trends can be predicted based on past observations.

A fundamental shift in electricity consumption, similar to what the industry has seen during and after the 2008 recession, causes earlier data to potential bias the regression analysis. Increasing energy efficiency, changes to consumer behavior, and sectoral changes in the economy fundamentally shifted the electricity consumption. Across the country, it took several years to reach pre-2008 peak loads again as high electricity consumptive industries were shut down, consumers changed habits and used less electricity, and electricity end uses became more efficient. This is why we see a gradual flattening of load forecasts every year, as a new data point is added to the regression model, the load forecast corrects downward.

A similar bias could be introduced due to consumer behavior in a post COVD-19 power sector. According to DESC, "weather-normal electric demand for the month of April was down nearly ten percent on a relative basis to the prior 2018-2019 two-year average. In May 2020, demand began to improve, but was still down approximately five percent on a relative basis to the prior 2018-2019 two-year average."[31] This makes the likelihood of over forecasting electricity load much more likely. The likely economic recession following COVID-19 could make for long-term load reductions lasting years, delaying the need for new capacity resources required for load growth.

A second reason the DESC forecast could be overstated is based on recent historical winter peak loads. According to DESC, the winter peak demand for the 2019-2020 season, which occurred on [redacted][32] This is [redacted] lower than the weather normalized IRP forecast of 4,891 MW.[33] The 2019

[31] Dominion Energy, *Actions in Response to COVID-19, Docket No. 2020-106-A,* Page 2.
[32] DESC Confidential Response to ORS 6-9, attached as Exhibit DS-7.
[33] Direct Testimony of Eric H. Bell, Exhibit 1, "2020 Integrated Resource Plan," Page 12.

peak load was also [redacted][34] While mild weather was likely a primary driver of recent winter peak loads, other recent historical values were well below the IRP 2020 assumption. Historical summer and winter peak loads for DESC is provided in Figure 6 below, which indicates a long-term average winter peak load of approximately 4,600 MW, or 6% lower than DESC's assumption for 2020.

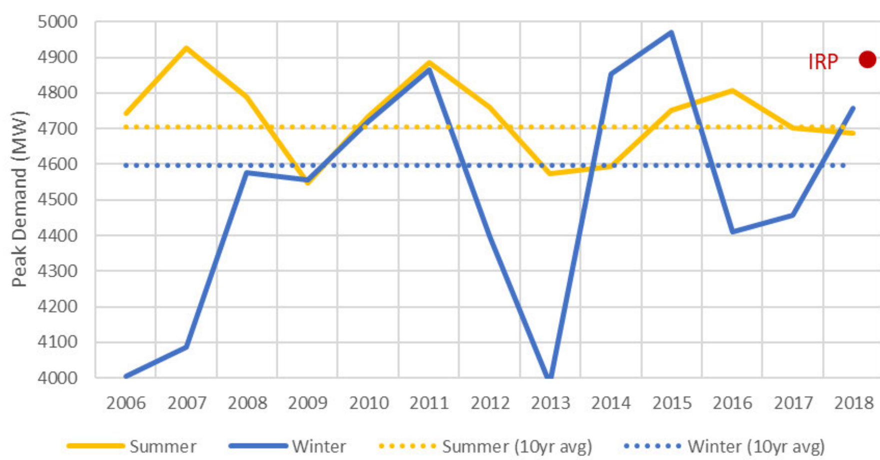

Figure 6: DESC Historical Summer and Winter Peak Demand from FERC 714 Data

In addition, there appears to be a disconnect for the first year starting point of the DESC peak load analysis. After evaluating load factors from 2006-2018, the 2020 starting point of the DESC winter peak load factor is low. Load factor is a measure of the average load relative to the peak load. The lower the load factor, the higher the peak load. While winter load factors are declining overtime as residential load growth outpaces industrial load growth, the IRP assumed a load factor of 0.56, which is significantly lower (6.7%) than recent observations.

[34] DESC Confidential Response to ORS 2-18, attached as Exhibit DS-3

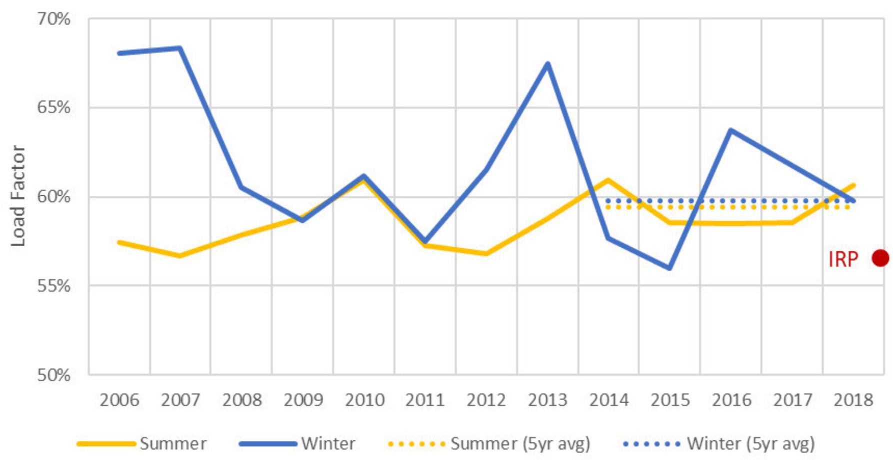

Figure 7: DESC Historical Summer and Winter Load Factors from FERC 714 Data

It should be noted that winter peak loads are volatile from year to year because they are driven by rare extreme weather events. While the utility needs to be prepared for these events, this is the purpose of the 14% winter reserve margin, which is larger than the summer reserve margin.

I recommend that the Commission require DESC to utilize a load factor for the first year of the load forecast that is in line with the average of the prior five years. This will result in a lower winter peak load starting point. The growth rates from the DESC load forecast should be based on this starting point. This was the methodology used in my modeling analysis.

Q: How would a high winter peak load forecast affect the IRP results?

A: A high load forecast, like the one used in DESC's IRP, specifically the winter peak load forecast, requires more capacity additions in future years to maintain the reserve margin criteria. It also requires more replacement capacity for any retirements. Based on DESC's analysis, it is primarily the winter peak demand, as opposed to the summer peak, that is driving new investment and retirement decisions. It should be noted that while peak demand events can occur in the winter season, these tend to be rare, short-term events that could be better addressed by demand response, energy efficiency, and consumer behavior rather than new investments in conventional generating equipment.

Q: What is your recommendation for the DESC load forecast?

A: Based on my observations outlined above, I recommend using a lower load forecast for the IRP. DESC evaluated three load scenarios, a Base Forecast, a High Scenario, and a Low Scenario.[35] Based on my review, DESC's Low Scenario for a low load growth rate of 0.25% should be used as the base case assumption. I also recommend adjusting the first-year winter peak demand to align with the previous 5-year average load factor of 0.60, which would translate to a winter peak demand of 4,583 MW, which is more in line with historical data.

RISKS OF CONTINUED COAL OPERATIONS

Q: Are there risks of continued coal operations for DESC ratepayers?

A: Yes, there are several risks associated with continued coal operations, many of which were not evaluated in the IRP but warrant a qualitative discussion. These include

[35] Direct Testimony of Eric H. Bell, Exhibit 1, "2020 Integrated Resource Plan," Page 11.

reliability risks of aging infrastructure, need for increased flexibility for future uncertainty, potential for more stringent federal or state environmental policy, and cost uncertainty in environmental upgrades.

Q: What are the reliability risks of continued coal operation?

A: DESC's coal power plants constitute large blocks of power in their resource portfolio. The average capacity of the four coal units at Wateree, Williams and Cope is 427 MW, which represents approximately 10% of DESC's peak load. When the coal units go on forced outage, it represents a large loss of capacity in a single outage (also known a as a single contingency). Wateree and Williams were built in the early 1970s and are now approaching 50 years of age. The increased age of the equipment, and the increased cycling duty required of them due to low natural gas prices and increased solar penetration, leads to increased degradation and higher forced outage rates.[36]

An example of potential long duration forced outages is the recent failure of Wateree Unit 2, which experienced a recent explosion and has been on outage since January 30, 2020.[37] This represents a large loss of capacity for DESC stemming from a single failure mode. In contrast, battery storage and solar PV technology is highly modular and can be distributed across the system. This means the likelihood of a failure removing an equal amount of battery storage or solar PV capacity compared to Wateree Unit 2 would be highly unlikely and easily designed to prevent.

[36] National Renewable Energy Laboratory, "Power Plant Cycling Costs," April 2012, available at: https://www nrel.gov/docs/fy12osti/55433.pdf.

[37] DESC Response to ORS 6-4, attached as Exhibit DS-6.

This type of supply-side uncertainty is one of the primary factors that influences DESC's reserve margin requirement, along with load uncertainty and weather. With fewer large contingencies, there is less risk of lost capacity due to a single event. Replacing coal generation with a diverse and distributed set of smaller solar and storage plants would decrease this reliability risk for DESC and could allow for a decreased 12% summer and 14% winter base reserve margin requirement and fewer capacity additions required for DESC ratepayers.

Q: Will the future power system require flexibility, and are DESC's coal plants best suited to provide that flexibility?

A: Across the power industry there is growing consensus that generation flexibility is increasingly important for modern power systems.[38] Increased variability from wind and solar, changing load patterns, and growing electrification trends all indicate that absent investment in new technologies, the existing generation fleet will need to be operated in a more flexible manner. [39] This will require generation to start and stop (cycle) more often, operate at lower loading levels, and ramp more frequently. This was not the original intended use of DESC's coal fleet, which was designed to be operated as "baseload" generation with minimal cycling and load following duty. While the coal fleet can change operations, it may come at a risk of increased cost, equipment degradation, and flexibility shortfalls.[40]

[38] International Renewable Energy Agency, "Power System Flexibility for the Energy Transition," November, 2018, available at https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2018/Nov/IRENA_Power_system_flexibility_1_2018.pdf.
[39] National Renewable Energy Laboratory, "Advancing System Flexibility for High Penetration Renewable Integration," available at https://www.nrel.gov/docs/fy16osti/64864.pdf.
[40] Abang, R., Wei, S., Krautz, H.J., "Impact of increased power plant cycling on the oxidation and corrosion of coal-fired superheater materials," *Fuel,* Volume 220, May 2018.

Continued growth of solar PV, electricity loads from increased electric vehicle adoption, and a "peakier" load profile (higher peak loads relative to the average daily load) will increase the need for flexibility. Legacy coal generation is not well suited to provide the expected needs of increased flexibility. Rather that investing a quarter billion dollars in environmental upgrades for legacy coal generation, DESC ratepayers are better suited to invest their money in new, more flexible technology that can better adapt to future uncertainties of renewable growth, electric vehicles, and changes to customer loads.

Q: What are the risks associated with future environmental policy or CO_2 emission pricing?

A: As DESC's IRP indicates, there are financial risks for ratepayers associated with potential environmental policies and CO_2 pricing.[41] Changes in state or federal policy could change the least cost plan put forward by DESC, as evidenced by DESC's own analysis reproduced in Table 3 below. The coal retirement scenario, Resource Plan 8 ("RP8"),[42] changes order from the 8th, and most expensive portfolio, to the least cost plan when a \$25/ton CO_2 price is assumed, as indicated in Table 3, below.

Even in the Base Gas price assumption scenarios, the 3% higher cost associated with RP8 would be reduced further if DESC includes other societal costs and health effects of continued coal operation.[43,44] If these costs were included in the analysis, the 3% premium would be reduced further making RP8 the likely least cost plan assuming a

[41] Direct Testimony of Eric H. Bell, Exhibit 1, "2020 Integrated Resource Plan," Page 18.
[42] Resource Plan 8 (RP8) was the resource plan evaluated by DESC to represent coal retirements. The portfolio replaced Wateree and Williams coal units with combined cycle, solar, battery storage, and ICTs.
[43] Machol, B. and Rizk, S, "Economic Value of U.S Fossil Fuel Electricity Health Impacts," *Environmental International,* Vol 52, February 2013, Pages 75-80.
[44] Conca, J., "Choking our Health Care System with Coal," *Forbes*, available at: https://www forbes.com/sites/jamesconca/2015/11/05/choking-our-health-care-system-with-coal/#48da90616de4.

$0/ton CO_2 price – even if all of DESC's capital cost, load, and other assumptions are not adjusted to more realistic values.

Table 3: DESC's Resource Plan Net Present Value ("NPV") Rankings[45]

Resource Plan Levelized NPV Rankings for Medium DSM

Resource Plan ID	Resource Plan Name	$0/ton CO_2, Low Gas	$0/ton CO_2, Base Gas	$0/ton CO_2, High Gas	$25/ton CO_2, Low Gas	$25/ton CO_2, Base Gas	$25/ton CO_2, High Gas
RP1	CC	6	5	5	7	6	6
RP2	ICT	1	1	2	3	4	3
RP3	Retire Wateree	5	6	7	4	3	5
RP4	Retire McMeekin	2	3	4	6	7	8
RP5	Solar + Storage	8	7	6	8	8	7
RP6	Solar	4	4	3	5	5	4
RP7	Solar PPA + Storage	3	2	1	2	2	2
RP8	Retire Coal	7	8	8	1	1	1

Resource Plan Levelized NPV for Medium DSM ($000)

Resource Plan ID	Resource Plan Name	$0/ton CO_2, Low Gas	$0/ton CO_2, Base Gas	$0/ton CO_2, High Gas	$25/ton CO_2, Low Gas	$25/ton CO_2, Base Gas	$25/ton CO_2, High Gas
RP1	CC	$1,166,528	$1,249,160	$1,427,424	$1,385,375	$1,469,436	$1,668,590
RP2	ICT	$1,145,532	$1,231,667	$1,416,354	$1,370,853	$1,461,736	$1,665,599
RP3	Retire Wateree	$1,165,235	$1,251,077	$1,444,505	$1,372,378	$1,460,334	$1,666,688
RP4	Retire McMeekin	$1,154,191	$1,239,802	$1,425,558	$1,380,307	$1,470,231	$1,675,337
RP5	Solar + Storage	$1,186,034	$1,266,727	$1,435,093	$1,394,516	$1,475,915	$1,669,182
RP6	Solar	$1,163,394	$1,246,165	$1,423,590	$1,378,987	$1,465,797	$1,665,995
RP7	Solar PPA + Storage	$1,154,889	$1,236,518	$1,413,532	$1,370,024	$1,455,686	$1,654,813
RP8	Retire Coal	$1,183,714	$1,267,624	$1,467,499	$1,356,160	$1,438,706	$1,646,153

Q: What are the risks associated with environmental retrofits?

A: According to DESC, environmental retrofit and control technology would be required for continued use of Wateree and Williams coal plants under the,

> *"Environmental Protection Agency's ("EPA") Steam Electric Effluent Limitation Guidelines ("ELG"): This regulation is anticipated to require significant capital expenditures for flue gas desulphurization ("FGD") wastewater treatment at both*

[45] Direct Testimony of Eric H. Bell, Exhibit 1, "2020 Integrated Resource Plan," Page 18.

> *Wateree and Williams Stations and for modifications to limit or eliminate the discharge of ash transport water at Williams Station."*[46]

DESC stated that the capital costs for the required upgrades are anticipated to be $101.7M at Wateree Station for flue-gas desulfurization (FGD) wastewater treatment and $126.8M at Williams Station for both bottom ash transport water treatment and FGD wastewater treatment. In addition, it was assumed that fixed O&M increased $3.33M/year at Wateree Station and $4.16M/year at Williams Station beginning in 2026 because of the installed ELG mitigation equipment.[47] As DESC stated, these are cost estimates for the installation of these upgrades, so there is always a risk of cost overruns.[48] Unlike solar and battery storage, which can be developed by independent power producers who take on risks of cost overruns, DESC ratepayers would bear the risk of cost overruns for environmental retrofits, which according to the Charles River Associates Report could run upwards of $900 million.[49] Even if these upgrade costs were locked-in at $228.5M, this represents an investment that could be better spent on investing in new, modern, and clean technology. The coal units are already seeing decreased utilization and capacity factors, are increasingly uneconomic to gas and renewable generation, and are seeing increased failures and degradation. Continued use of 50-year old infrastructure for another 20-years as suggested by DESC's IRP is imprudent.

[46] DESC Response to ORS 1-17, attached as Exhibit DS-2
[47] DESC Response to ORS 2-26, attached as Exhibit DS-4.
[48] In fact, the Charles River Associates Report estimates that environmental compliance costs are estimated at $900 million. *See* Direct Testimony of Eric H. Bell, Exhibit 2. "Independent Review of the 2020 DESC IRP." Page 92.
[49] Id.

INDEPENDENT MODELING OF ALTERNATIVE PORTFOLIOS

Q: Did you perform independent modeling of the DESC system to evaluate alternative resource portfolio options?

A: Yes. To better evaluate alternative portfolio options, I conducted an independent modeling of DESC's system. This was done by recreating the models and processes developed by DESC, to the closest extent reasonable, and testing alternative portfolios to quantify the total operating costs, fixed costs, and capital costs of new portfolios. This modeling effort was done to specifically test the impacts of earlier retirement of the Wateree and Williams coal plants, and their replacement with solar and storage technologies exclusively.

Q: What methodologies and software tools did you use for the modeling?

A: To the extent possible, I utilized the same methodology as DESC to test alternative resource portfolios, with limited changes to inputs and assumptions to make for a direct comparison. I utilized chronological, 8,670 hour per year, production cost simulations to quantify total generation costs of each portfolio. Similar to DESC, the production cost simulations quantify fuel costs, variable operations and maintenance costs, startup costs, emissions costs, and fixed operations and maintenance costs for each portfolio. I then utilized the same workbooks as DESC to calculate the annualized capital costs and net present value (NPV) of each portfolio.

Unlike DESC, I utilized the PLEXOS modeling software for my analysis. PLEXOS is a third-party industry recognized energy modeling software developed by Energy

Exemplar and used by utilities, grid operators, developers, and consultants worldwide.[50] DESC stated that their next IRP analysis will utilize this software as well.[51] While PLEXOS has long-term optimal capacity expansion capability, I utilized the model's short-term chronological production cost modeling feature to ensure consistency with DESC methodologies.

To ensure a valid comparison to the DESC portfolios, I also reran DESC portfolio RP2 to serve as a reference case for alternative portfolios to be compared against. While the total NPV of this scenario does not exactly align to DESC's analysis due to different software tools, load growth, etc., it serves as a valid reference case for comparison.

Q: What underlying data did you use for the analysis?

A: I developed the PLEXOS DESC database utilizing the information and data provided in the IRP, as well as DESC's responses to Sierra Club's Second Set of Data Requests, including DESC's PROSYM datafiles.[52] I would like to thank DESC for providing this data and transparency to the modeling files utilized in this analysis. This allowed for an independent review of system modeling.

Q: Did you make any changes to DESC's inputs or assumptions?

A: Yes, but to the extent possible I intentionally limited the amount of changes made to DESC's inputs and assumptions to make it as direct of a comparison as possible. I also

[50] Energy Exemplar, *PLEXOS Market Simulation Software,* https://energyexemplar.com/solutions/plexos/.
[51] DESC Response to ORS 5-13, attached as Exhibit DS-5. DESC's response to ORS 5-13 actually states "Request 1-20" and "Response 1-20" on the document. Sierra Club believes this was a typographical error since DESC was cross-referencing their response to 1-20 in its answer to ORS 5-13. As part of Exhibit DS-5, I am also attaching an excerpt from Office of Regulatory Staff's Fifth Request to show the actual 5-13 request.
[52] A full copy of these responses is available for the Commission upon request.

reran DESC RP2 with the same model and updated assumptions to serve as the reference case. The following DESC inputs and assumptions were modified for this analysis:

- **Capital Cost Assumptions**: The capital cost of combustion turbines was updated to $899/kW and the capital cost of battery storage was updated to $1284/kW as discussed earlier in this testimony. These adjustments were made only to the NPV calculation workbooks and not input directly into PLEXOS.
- **Interconnection Cost of Battery Storage & Solar**: The interconnect cost of battery storage and solar PV was made consistent with the assumption used by DESC for combustion turbine technology at $15.75/kW.
- **Economic Life of Battery Storage**: the economic life of the battery storage, utilized in the fixed charge rate calculations, was updated from 10 to 15 years to better reflect current technology and assumptions used throughout the industry.[53,54]
- **Load Forecast:** The annual energy forecast was changed to use the DESC low load scenario and winter peak demand was reduced based on the average of the last five years of load factors seen by DESC, as discussed earlier in this testimony.
- **Load Profile:** The chronological, hourly load profile and solar profiles were adjusted to use publicly available data and the same weather year (2017). This is a best practice for modeling grids with increasing solar PV penetration. The load

[53] NREL (National Renewable Energy Laboratory). "2019 Annual Technology Baseline." Golden, CO: National Renewable Energy Laboratory, available at: https://atb nrel.gov/electricity/2019.
[54] Lazard, "Levelized Cost of Energy Analysis, Version 13," November 2019, available at: https://www.lazard.com/media/451086/lazards-levelized-cost-of-energy-version-130-vf.pdf.

profile used FERC 714 hourly load filings[55]and the solar data utilized NREL's National Solar Radiation Database (NSRDB) and System Advisor Model.[56]

Q: What scenarios did you evaluate?

A: I evaluated several scenarios that retired the Williams and Wateree coal plants, starting in 2026, and replacing them with a portfolio of solar and storage technologies. Solar and storage was added to the model to ensure that the winter reserve margin target of 14% was maintained throughout the study period. The scenarios evaluated include the following:

Scenario 1: DESC RP2, Business-as-usual, No Coal Retirements

- Adjusts load and peak demand down to be consistent with other scenarios,
- Updated capital cost assumptions for CT units to be consistent with other scenarios,
- Reran in PLEXOS with our database to provide consistent reference case,
- Assumes continued use of Williams and Wateree coal plants,
- Includes $228 million capital expense in 2026 to make Williams and Wateree coal plants ELG compliant, consistent with DESC RP2 scenario assumptions,
- No new capacity additions required in the study period.

Scenario 2: Williams & Wateree Retirement in 2026, Replacement with 460 MW of PV and Batteries

- Assumes retirement of Williams & Wateree coal plants in 2026, no new gas additions throughout the study period,
- Replacement with 460 MW of PV, 460 MW / 1840 MWh of batteries in 2026,
- Annual additions of 40-50 MW of PV and batteries starting in 2029,
- Winter reserve margin maintained at 14% throughout study period.

Scenario 3: Williams & Wateree Retirement in 2028, Replacement with 460 MW of PV and Batteries

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[55] Federal Energy Regulatory Commission, "Form No. 714 - Annual Electric Balancing Authority Area and Planning Area Report," available at: https://www.ferc.gov/industries-data/electric/general-information/electric-industry-forms/form-no-714-annual-electric/data.
[56] National Renewable Energy Laboratory, *National Solar Radiation Database,* available at: https://nsrdb.nrel.gov/.

- Scenario 2, but deferred retirement of Williams & Wateree to 2028, no new gas additions throughout the study period,
- Replacement with 460 MW of PV, 460 MW / 1840 MWh of batteries in 2026, annual additions of 40-50 MW of PV and batteries starting in 2029.

Scenario 4: Williams & Wateree Retirement in 2026, 2x Replacement with PV and Batteries

- Scenario 2, but replacement with 920 MW of PV, 920 MW / 3,680 MWh of batteries in 2026.
- This represents a high solar and high battery scenario.

Scenario 5: Williams & Wateree Retirement in 2026, 2x Replacement with PV, 1x Batteries

- Scenario 2, but replacement with 920 MW of PV, but maintains 460 MW of batteries added in Scenario 2.
- This represents a high solar, and base case battery scenario.

Q: In Scenarios 2-5, why did you retire 1,294 MW of coal capacity, but only replace it with 460 MW of solar and storage capacity?

A: Each scenario evaluated the retirement of Williams and Wateree coal capacity (1,294 MW) and replacement with enough storage to meet the winter reserve margin requirement of 14%. Solar was added in a similar amount to add some, but not all, of the energy that the coal plants provide in the Scenario 1 Reference Case (RP2). The remaining capacity and energy are provided by existing gas resources, and limited imports when necessary. Hourly imports were limited to quantities seen in recent historical operations. Scenarios 4 and 5 tested the effects of increasing solar and battery storage additions above and beyond the amounts required for reserve margin compliance. The resulting forecast of summer and winter loads and resources is provided in Table 4 below.

Table 4: Forecast of Winter Loads and Resources, Alternative Portfolio, Scenario 2

	SCE&G Forecast of Winter Loads and Resources - 2020 IRP Update (MW)															
	YEAR	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
		W	W	W	W	W	W	W	W	W	W	W	W	W	W	W
Load Forecast																
3	Gross Territorial Peak	4583	4604	4624	4623	4639	4657	4675	4689	4702	4738	4781	4823	4862	4903	4941
System Capacity																
4	Existing	5915	5915	5915	5915	5915	5915	5915	5081	5091	5091	5131	5171	5221	5261	5311
5	Existing Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Demand Response	224	226	228	230	234	239	249	261	275	276	277	278	279	280	281
	Additions															
7	Solar Plant	0	0													
8	Peaking/ ntermediate							460	10		40	40	50	40	50	40
9	Baseload															
10	Retirements							-1294								
11	Total System Capacity	6139	6141	6143	6145	6149	6154	5330	5352	5366	5407	5448	5499	5540	5591	5632
12																
13	Total Production Capability	6139	6141	6143	6145	6149	6154	5330	5352	5366	5407	5448	5499	5540	5591	5632
Reserves																
14	Margin (L13-L3)	1556	1537	1519	1523	1510	1497	655 3	663 3	664 2	669	667 4	676 1	678 6	688 6	691 5
15	% Reserve Margin (L14/L3)	34 0%	33 4%	32 9%	32 9%	32 5%	32 1%	14 0%	14 1%	14 1%	14 1%	14 0%	14 0%	14 0%	14 0%	14 0%

Q: What are the results of the alternative portfolio analysis?

A: The results of the analysis are provided in Table 5, Table 6 and Figure 8 below, which provides a breakdown of total NPV for each scenario, along with a breakdown of costs. As the tables and figure indicate, the coal retirement scenarios with a replacement of solar and storage are the least cost options for DESC ratepayers, as compared to DESC's RP2. The Williams and Wateree coal retirement and replacement in 2026 is 2.1% lower cost than continued coal operation. This is because low natural gas prices, decreasing solar and storage prices, low load growth, adjusted capital cost assumptions, and required environmental retrofits for Wateree and Williams make the continued utilization of coal generation uneconomic. While Scenarios 2-5 all have higher new generation capacity costs for the additions of solar and battery capacity, all but Scenario 4 make up for this increase through fuel cost savings and lower operations and maintenance costs, providing net benefits to DESC ratepayers.

The findings of this analysis demonstrate that a least cost plan can be developed, using industry standard assumptions, where the Williams and Wateree coal plants are retired early and replaced with clean, modern, and cost-effective technologies. This would benefit DESC ratepayers with reduced electricity costs, a cleaner electric power grid, and one that is less susceptible to the risks of continued coal operation.

Table 5: Resource Plan Levelized NPV ($000)

Scenario	Description	NPV	Rank	Delta to Scenario 1
Scenario 1	Business-as-Usual, DESC RP2, No Coal Retirements	1,024,990	4	-
Scenario 2	Coal Retirement in 2026, PV & Battery Replacement	1,013,573	2	-1.1%
Scenario 3	Coal Retirement in 2028, PV & Battery Replacement	1,010,594	1	-1.4%
Scenario 4	Coal Retirement in 2026, 2x PV & 2x Battery Replacement	1,066,516	5	4.1%
Scenario 5	Coal Retirement in 2026, 2x PV & 1x Battery Replacement	1,020,267	3	-0.5%

Table 6: Resource Plan Levelized NPV by Cost Category

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
Fuel Costs	604,452	564,660	568,356	525,894	526,923
Fixed Fuel Costs	64,763	53,707	55,342	53,707	53,707
Non-Fuel Variable Costs	36,826	35,721	35,836	34,168	34,192
Fixed O&M Costs	249,206	212,030	216,616	212,030	212,030
CO2 Costs	0	0	0	0	0
Purchases & Sales	574	2,259	2,063	1,769	1,617
New Generation Capacity Costs	29,732	105,758	92,942	199,510	152,359
DSM Costs	39,438	39,438	39,438	39,438	39,438
Total Costs	**1,024,990**	**1,013,573**	**1,010,594**	**1,066,516**	**1,020,267**

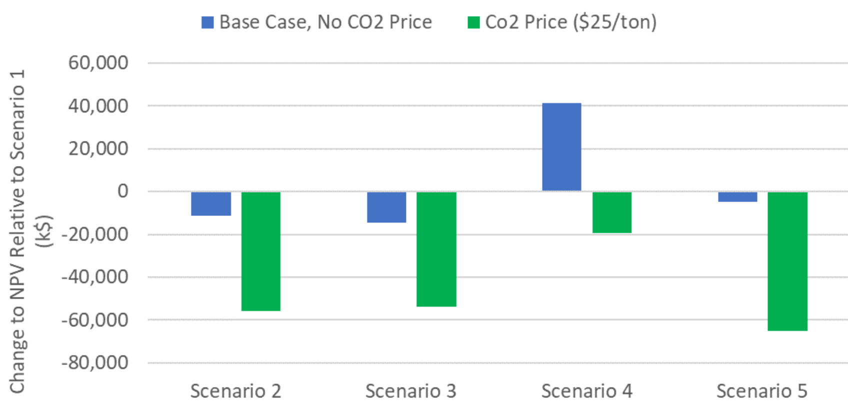

Figure 8: Change to Portfolio NPV Relative to Scenario 1 (DESC RP2), ($000)

Q: Did you evaluate the portfolios assuming a price on CO_2?

A: Yes, the portfolios were also analyzed assuming a $25/ton price on CO_2 starting in 2025, in the same manner as the DESC scenarios. Including a CO_2 price, as seen in the DESC analysis, improves the economics of the coal retirement and replacement portfolios relative to the DESC RP2 least cost plan. In the alternative portfolios, the replacement of coal with solar and battery storage becomes more economic and each of the four alternative scenarios becomes more economic than the Scenario 1 Reference Case. Scenario 5, with additional solar PV, becomes the least cost plan. This illustrates the increased benefits associated with renewable energy when a CO_2 price is introduced. Table 7, below, provides the NPV and portfolio rankings.

Table 7: Resource Plan Levelized NPV with a $25/ton CO2 price ($000)

Scenario	Description	NPV	Rank	Delta to Scenario 1
Scenario 1	Business-as-Usual, DESC RP2, No Coal Retirements	1,216,208	5	-
Scenario 2	Coal Retirement in 2026, PV & Battery Replacement	1,160,528	2	-4.6%
Scenario 3	Coal Retirement in 2028, PV & Battery Replacement	1,162,467	3	-4.4%
Scenario 4	Coal Retirement in 2026, 2x PV & 2x Battery Replacement	1,197,008	4	-1.6%
Scenario 5	Coal Retirement in 2026, 2x PV & 1x Battery Replacement	1,151,208	1	-5.3%

RECOMMENDATIONS

Q: Please summarize your recommendations for the Commission.

A: The Commission should reject the IRP and require DESC to reanalyze the portfolios with more accurate capital cost assumptions and a load forecast that is more in line with recent historical data and the effects of COVID-19.

The Commission should also consider alternative portfolios for DESC's IRP, specifically ones that retire the Williams and Wateree coal plants and replace them with clean, modern, and cost-effective technologies. The commission should require DESC to update their capital cost assumptions for candidate technologies, and if possible, utilize actual project bid data for resource planning. This is a best practice being adopted throughout the industry. Examples of this include PNM's San Juan Replacement[57] and HECO's Integrated Grid Planning[58] efforts. This ensures that new candidate resources are evaluated based on current pricing trends rather than aging industry reports. This information is critical for near-term retirement and replacement decisions.

The Commission should also take into account the reality of low load growth and naturally occurring energy efficiency (efficiency gains not attributed directly to, or incentivized by, utility-sponsored programs), and sectoral changes in the economy occurring in South Carolina. A lower load growth assumption would limit the risk of potential overbuild of new capacity to DESC ratepayers.

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[57] Public Service of New Mexico, *Powering the Future - Exit from Coal*, https://www.pnmforwardtogether.com/poweringthefuture
[58] Hawaiian Electric Company, *Integrated Grid Planning,* https://www.hawaiianelectric.com/clean-energy-hawaii/integrated-grid-planning

In addition, the winter reserve margin criteria requires increased scrutiny as it is a primary driver of DESC's IRP results. The Commission should open a docket specifically related to reserve margin requirements and resource adequacy analysis. This analysis quantifies the reliability of the system and whether it meets reliability criteria by quantifying loss of load expectation (LOLE) as a number of days per year of unserved load. Changing resource adequacy methods is an important topic in the industry right now and currently being evaluated by many grid operators, including MISO, PJM, NYISO, and CAISO.

Finally, the Commission should open a new docket specifically related to the retirement and replacement of Williams and Wateree coal plants. This docket should evaluate the reliability risks and environmental costs of their continued operation as well as options to replace legacy coal technology with state-of-the-art clean energy. This docket should include a collection of resource bids to replace the coal units to provide accurate pricing data for DESC and the Commission.

Q: Does this conclude your testimony?

A: Yes.